Generation Planning

NB POWER

ANNUAL REPORT OF GENERATION PLANNING

1985/86 - 1999/2000

SYSTEM PLANNING DIVISION
SEPTEMBER 1985

1985/86
REPORT OF GENERATION PLANNING
FOR
THE 15 YEAR PERIOD 1985 TO 2000

TABLE OF CONTENTS

SECTION			PAGE
I	SUMMARY		1
II	INTRODUCTION		4
III	LOAD FORECAST		6
IV	NB POWER SYSTEM CAPABILITY		8
V	PLANNING CRITERIA		13
	a)	Reliability Criteria	13
	b)	Environmental Criteria	14
VI	LOAD AND RESOURCES REVIEW		15
	a)	Peak Electrical Capability Assessment	15
	b)	Sustained Electrical Capability Assessment	15
VII	OPTIONS FOR THE FUTURE		19
	a)	General	19
	b)	Nuclear	19
	c)	Coal Fired Thermal Generation	20
	d)	Conversion of Oil-Fired Thermal Generation	
		i) Coal Conversion	20
		ii) Coal-Water Mixture Demonstration	21
		iii) Circulating Fluidized Bed Demonstration Project	23
		iv) Venezuelan Bitumen	24
		v) Natural Gas Conversion	24

TABLE OF CONTENTS (Cont'd)

SECTION		PAGE
	e) Hydraulic Generation	25
	i) Tidal Power Generation	25
	ii) Other Hydraulic Generation	26
	f) Purchases	28
	g) Combustion Gas Turbine Generation	30
	h) Alternate Energy Sources	30
	i) Load Management	31
	j) Energy Conservation	31
	k) Waste Heat Utilization	32
	i) Mactaquac	32
	ii) Surface Heated Greenhouses	32
VIII	PRESENTATION OF A FEASIBLE EXPANSION ALTERNATIVE	34
IX	CONCLUSIONS	39
	APPENDIX A	41
	REFERENCES	45

FIGURES AND TABLES

PAGE

TABLES

TABLE I - Generating Station Capabilities 10

TABLE II - Summary - Forecast Electrical Demand Vs. Generating Capability 17

TABLE III- Load and Resource Review Reserve Requirements 22

TABLE IV - Sustained Electrical Capability Criterion

TABLE V - Peak Electrical Capability Criterion

FIGURES

FIGURE 1 - NB Power In-Province Annual Peak Demand ...7

FIGURE II- Energy Sources to Meet In-Province Load Existing System 12

FIGURE III - Energy Sources to Meet In-Province Load; Existing System with Coleson Cove Converted to Coal-Fired Operation 22

FIGURE IV - Energy Sources to Meet In-Province Load Expanded System - Alternative 1 37

FIGURE V - Energy Sources to Meet In-Province Load expanded System - Alternative 2 38

I SUMMARY

NB Power reviews and updates annually its long range generation and transmission expansion plans. This report relates specifically to the generation planning process.

The Annual Load Forecast 1985-2000 (1) provides the basis for determining the requirement for new generation to be added to the NB Power system.

Alternative generation development options are reviewed for the period 1985-2000 to provide the generating resources necessary to meet the load forecasted. From these alternative development options, plausible generation expansion plans are presented.

The quality of the environment has, in recent years, become a significant concern in the development of any form of generation. Project feasibility has therefore, of necessity, been expanded to include comprehensive environmental studies and impact assessments to satisfy provincial and federal regulatory processes. Project approval has become more complex and time consuming than in the past. Such additional requirements have increased the costs and lead times necessary from the planning process to the commercial operation of any new form of generation.

The following are some significant conclusions relative to NB Power's generation requirements to 99/2000.

1. The electrical energy requirements of the customers served by by NB Power are expected to grow at an average annual compound growth rate of 2.8% over the 15 year period ending March 31, 2000. The system net peak hourly demand is expected to grow at an annual compound growth rate of 2.9% per year over the same period.

2. Considering the reserve generating capacity required to provide allowance for generating equipment to be shutdown for maintenance and to insure that sufficient power will remain available should the output of a major generating unit be unexpectedly cut off from the system for any reason, NB Power presently has sufficient generation installed to meet its technical requirements to the year 1992.

3. Conversion of existing oil-fired thermal generating units so that they can burn coal (as well as oil) has been a primary mechanism for reducing oil dependency for electric utilities. NB Power has investigated and is continuing to prepare for large scale conversions at the earliest appropriate date. The high capital cost of conversion makes a full scale commitment to that course of action more difficult in this face of currently soft oil prices. The most likely early conversions would occur at Coleson Cove and/or Dalhousie No. 1.

4. Circulating fluidized bed technology has provided NB Power with exciting new potential to build generating units capable of burning indigenous New Brunswick fuels, particularly high sulphur coal, because it has been shown to remove more than 90% of the sulphur during combustion. New Brunswick oil shales may prove acceptable as a sorbent/fuel in this process, increasing the development potential further. While the technology itself is now new, its application to electricity generation is just beginning and the first few commercial-sized units are only now coming into operation. Still, under the proper circumstances, including Federal financial assistance and support to cover some of the technical risks of scaling up the unit size, together with a suitable project labour agreement with the construction trades, NB Power could well decide to proceed with a 150-200 MW unit within the next year or two. Such a development would solidify and probably increase the demand for local New Brunswick coal.

5. Experimental analysis on coal water mixtures at NB Power's Chatham Generating Station has demonstrated a potential to utilize such a fuel source. Application of this technology on a larger scale is being considered as a possibility in the conversion of Dalhousie No. 1 unit.

6. In addition to conversion of existing generating units, the availability of western Canadian and US seaboard coal sources in ample supply at predicted long term competitive rates has led to the consideration of the development of added conventional low sulphur coal-fired capacity as one of NB Power's long range development options.

7. Point Lepreau II, while originally conceived as an export project only, could offer a viable new generation alternative for NB Power as well if there were to be residual capacity available beyond the principle export quantity. The high fixed charges of the nuclear unit would be significantly offset by the direct financial returns which could result for NB Power due to the second unit. These financial returns could take the form of site use charges, common facility rentals, and operating costs savings with a two unit site. Due to the proposed shared reliability feature between units I and II at Point Lepreau, NB Power's exposure to the performance risks of a single 635 MW unit would also be reduced. The key to this project remains the availability of the market and the willingness of the Federal Government to provide necessary financial support, including cost guarantees.

8. Consideration is being given to continued participation by New England utilities in the output of Point Lepreau 1 beyond the termination of the existing contracts in the event that the Lepreau II unit cannot go forward at this time. This would continue to ensure a reasonable level of access to unit

output without the excess of exposure to financial loss that would result from extended failure of the unit in the event of sole New Brunswick ownership.

9. Smaller scale opportunities exist in areas such as hydro-electric developments, and wood and waste projects, particularly as co-generators. NB Power believes that it is very important to remain abreast of developments in these areas and the utility would be most interested in proceeding with demonstration projects of this nature. Provision is being made in the Chatham demonstration unit for future installation of equipment which could burn wood waste products. The utility will also be concentrating its efforts in areas such as industrial load management and interconnection opportunities such as capacity purchases which might be used to delay the need for new generation additions or to make capacity-plus-energy export sales more attractive.

10. NB Power will continue its efforts to encourage its customers to practice the wise and efficient use of energy, and to give the strongest encouragement to conserve energy through the use of the best methods available for avoiding heat loss in the home.

II INTRODUCTION

NB Power is committed to supplying the electrical requirements of its customers at the lowest feasible cost on a long term basis consistent with safety, reliability and socio-environmental concerns. This requires that the planning for the system be an on-going process that is reviewed in detail annually.

The generation planning process starts with a comparison of the load forecasted for each year of the planning period with the generating capability available to meet that demand.

The load forecasted for each year in the future is given in "Load Forecast - 1985-2001" [1].

The comparison of generating capability with forecasted load yields the annual surplus (or deficit). By identifying the years in which deficits occur, the requirement for new sources of generating capacity is determined.

The generation planning process involves a review of alternative development options to meet the load forecasted for the period 1985-2000.

In the economic climate of the last decade, the generation planning process has become increasingly difficult. The shifts in energy price and supply, particularly for oil; the changing patterns of energy demand as a consequence of those shifts; the difficulties in financing major projects; the increased emphasis on environmental concerns and approval processes; and finally the financial uncertainties resulting from national and international economic effects have all enormously changed the environment in which long range planning must be conducted.

This new planning environment underlines the need for flexible development alternatives which will minimize the cost of deviations from assumptions due to the uncertainties inherent in our planning environment; for example, the impact of different load forecasts, fuel prices, financial parameters, new evolving combustion technologies, etc.

The system must be planned for at least 10 to 15 years in advance due to the long period of time necessary to get a facility in service once a decision to proceed has been made. Long lead times arise from such things as regulatory requirements, public hearings, property acquisition, financing arrangements, design, construction and commissioning. In addition to this 10 to 15 year planning period, the outlook over a longer term is generally studied. Due to forecast uncertainties, the results of these long term

investigations are of necessity more general in nature and more subject to change. They do, however, provide an indication of the long term viability of projects being considered to meet the requirements of the planning period.

In addition to planning generation facilities to supply requirements within the province of New Brunswick, NB Power has benefited from the construction of facilities in advance of need by selling the output of these facilities to other utilities on an interim basis. This concept of prebuilding for external sales permits NB Power to realize economic benefits from the construction and ownership of generating units. As well, the ability to sell part, or all of the output of existing and planned units greatly enhances NB Power's planning flexibility by providing the opportunity for consideration of development decisions to benefit the provincial economy and hence NB Power's customers. For example, continued sale of part of the output of Point Lepreau 1 can offer continued access to nuclear energy with reduced economic risk and the ability to move ahead with desirable options in meeting our customers essential requirements. These options may include consideration of evolving technologies, development of new mining resources and use of indigenous fuels to satisfy those requirements. It can alternatively provide an export market base which could advance the construction date for a Pt. Lepreau II unit to serve both in-province and the export market.

Additional economic benefits, operational support and planning flexibility have accrued from interconnections between NB Power and other utilities.

The benefits of interruptible energy purchases and sales are no longer secure because the transactions occur over very short time periods and may not be available in the longer term. A move to ensure more guaranteed quantities and long term contracts is considered advisable.

III LOAD FORECAST

The development of an expected load forecast is a vital element in a generation planning study. The number of years which must be forecast is a function of the time required to plan and construct new generation facilities. The load forecast must consider the magnitude of industrial and domestic growth, future economic policies, future energy policies, social trends as well as the costs of alternate energy sources.

The 1985 load forecast is reported in "Load Forecast 1985-2000" dated April, 1985. The report indicates that the electrical energy requirements of the customers served by NB Power are expected to grow at an average annual rate of 2.8% for the 15 year period ending March 31, 2000. The system net peak hourly demand is expected to increase at an annual compound growth rate of 2.9% per year. Figure I presents a graphical comparison of the 1984 and 1985 load forecasts along with actual peak loads experienced during the past five (5) years.

The difference between the two forecasts result in the 1984 forecast levels of energy supply and peak demand for the fiscal year 1991/92 to be attained one year earlier in 1990/91. This one year forward shift in load levels exists for the balance of the forecast period ending in the fiscal year 1999/2000.

Industrial and commercial applications of new technologies are expected to result in increased electrical loads. Heat pumps, mechanical vapour recompression systems and heat exchangers are key examples of known applications. The related potential electrical load is estimated at 37 Megatwatts over the forecasted period. This is about 7% of existing industrial load and has been included in the forecast.

In province electricity sales growth has been extremely strong in the past two years due largely to industrial recovery and conversions from oil to electric space heating in other sectors. An area of vulnerability for NB Power is its degree of reliance upon sales to the wood processing industry energy sales and 27% of total in-province energy sales in 1984/85. End-product diversification by the wood processing companies has lessened this vulnerability somewhat.

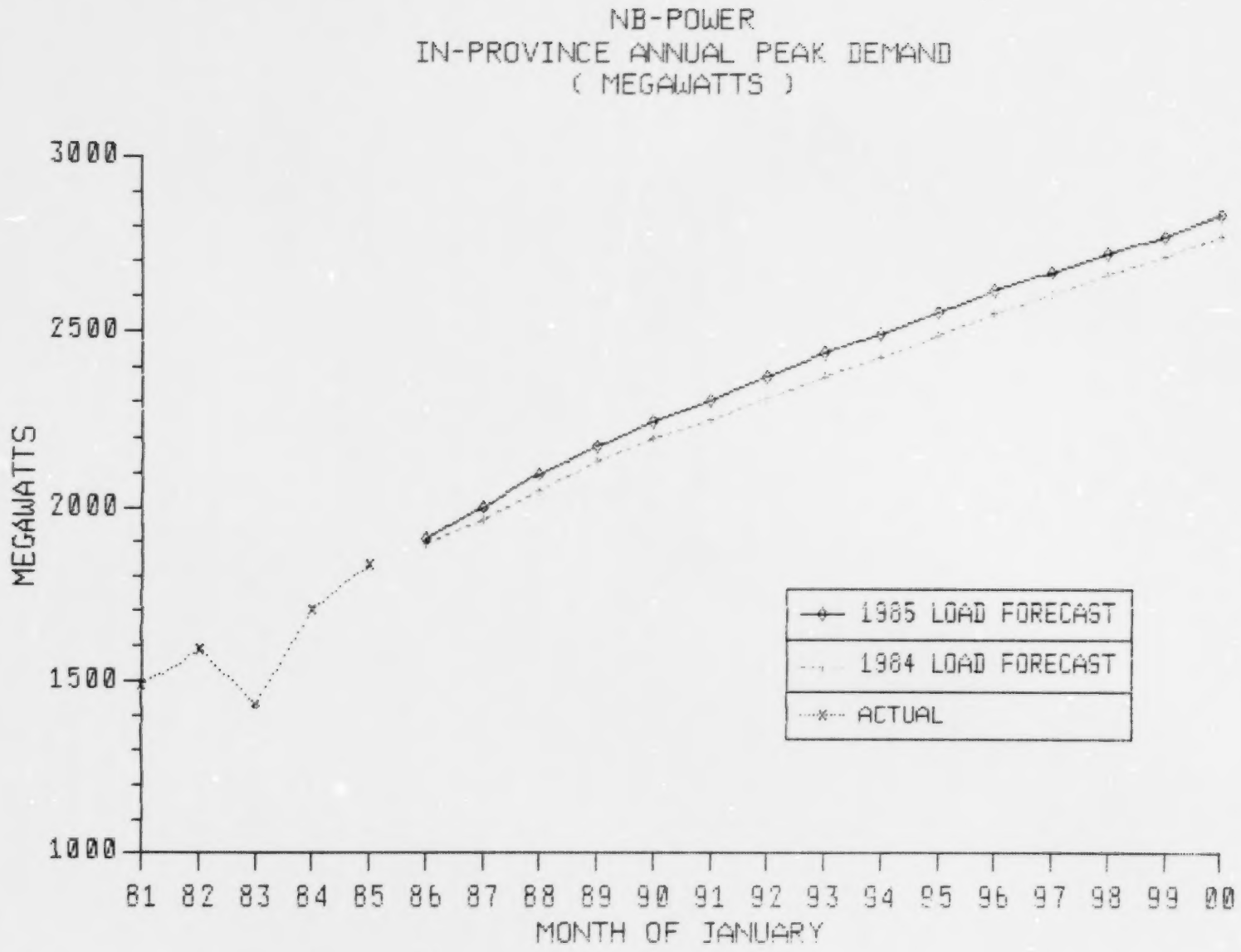

NB-POWER
IN-PROVINCE ANNUAL PEAK DEMAND
(MEGAWATTS)
MEGAWATTS
3000
2500
2000
1500
1000
81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00
MONTH OF JANUARY
1985 LOAD FORECAST
1984 LOAD FORECAST
ACTUAL

FIGURE I

IV NB POWER SYSTEM CAPABILITY

The NB Power system is comprised of a mix of hydro, nuclear, coal-fired thermal, oil-fired thermal, gas turbine and diesel generation.

The pattern of electric power consumption in New Brunswick has, to some degree, been influenced by the geography of the province and by traditional growth areas. To a large degree the existing thermal generating resources have been located in the northeast and southwest portions of the province because of the available deep water sites and fuel sources, while have largely been built at available development sites along the Saint John River and its tributaries.

A summary of the capability of the installed and committed generation is given in Table I. (Page 10)

The 1983 addition of the 635 MW Point Lepreau nuclear unit has resulted in significant savings to NB Power. In order to insure maximum benefit from a unit of this size, 230 MW of its output was sold to New England utilities during its early years. This output is currently scheduled to return to NB Power in 1991. Under terms of the agreement, the purchasing utilities are responsible for a proportionate share of all costs whether the unit performs or not. The significant financial risk associated with the possibility of a sustained failure of the unit is therefore alleviated for that portion of unit output purchased. In addition, the costs of reserve, or back-up generation to cover the contingency loss of their purchased portion of the unit output, must be covered by the purchasers. The costs of that reserve obligation are thereby removed from NB Power.

The 1984 completion of the raising of the Mactaquac Headpond by 3 feet has increased energy production to displace, on average, the equivalent of an additional 100,000 barrels of oil per year.

NB Power also purchases energy from neighboring utilities through its interconnections to displace more expensive generation. NB Power can also purchase capacity as needed to meet unplanned requirements or when such capacity is available and economically attractive. While Hydro Quebec has historically not sold firm capacity, it is generally known that they have excess energy for sale at least until 1990.

As a result, NB Power and Hydro-Quebec have constructed a second major interconnection between the two utilities. The Madawaska high voltage direct current (HVDC) facility located in Quebec just north of Edmundston, will in 1985 have a transfer capability of in excess of 500 MW. This and the

existing Eel River facility will have a combined transfer capability of over 1000 MW.

The present power costing agreement between NB Power and Hydro-Quebec is such that the cost saving to New Brunswick is based on the cost of the displaced fuel in the NB Power system. This means that a large block of energy used in New Brunswick is still related to thermal generating costs.

After displacing all possible higher cost New Brunswick energy, the lower cost Hydro-Quebec energy from these interconnections is then made available to the other Maritime Provinces as well as the U.S.

Energy sales have a positive effect on the country's balance of payments position not only from oil replaced in Canadian provinces, but also from the foreign exchange earned by sales of power to the U.S. The existing Hydro-Quebec interconnection at Eel River has consistently displaced over 4,000,000 barrels of oil fuel per year. The new interconnection at Madawaska has the capability to displace an equal amount.

A further benefit of purchasing Hydro-Quebec energy is that it is generated from hydro plants and its purchase results in a reduction of air emissions from thermal generating stations throughout the Maritimes. Therefore, any reduction in this purchased energy will result ion increased generation from internal thermal sources, higher emissions and consequent need to address associated concerns.

Figure II (Page 12) demonstrates the utilization of the existing and presently committed generation in the overall dispatch to supply the electrical energy requirement of the Province of New Brunswick assuming that Hydro Quebec surplus energy becomes unavailable in 1991. Note the increasing utilization of oil fuel in the nineties. This provides the background for consideration of further development options in that time frame, including both new firm purchases and internal generation capacity additions.

TABLE I
GENERATING STATION CAPABILITIES

HYDRO			THERMAL			
Plant	Unit	Capacity	Plant	Unit	Fuel	Capacity
Beechwood	1	36.0	Chatham	1	Coal/Oil	9.4
	2	36.0		2	Coal/Oil	19.9
	3	41.0				
			Coleson Cove	1	Oil	335.0(2
Grand Falls	1	15.3		2	Oil	310.0(3
	2	15.3		3	Oil	335.0(2
	3	15.3				
	4	15.3	Courtenay Bay	1	Oil	44.5
				2	Oil	12.3
Mactaquac	1	110.0		3	Oil	100.0
	2	110.0		4	Oil	97.0
	3	110.0				
	4	116.0	Dalhousie	1	Oil	103.0
	5	113.0		2	Coal/Oil	183.0(4
	6	113.0				
			Grand Lake	5	Coal	4.8
Milltown	1	0.70		6	Coal	4.8
	2	0.70		7	Coal	14.5
	3	0.70		8	Coal	57.1
	4	0.25				
	5	0.25	Grand Manan	5	Diesel	0.55
	6	0.40		6	Diesel	0.37
	7	0.60		7	Diesel	0.60
				8	Diesel	0.77
Musquash		5.2		9	Diesel	0.86
Sisson	1	8.5	Lepreau	1	Uranium	635.0(5
Tobique	1	10.0	Moncton	1	Gas	22.5
	2	10.0				
Total Hydro		883.5	Total Thermal			2291.0

NOTES:

-1- Capacity values are NET values derived by subtracting station service requirements from the unit's gross capability.

-2- Coleson Cove units 1 and 3 are available to NBEPC at 198 MW each until October 31, 1985 due to participation sales. They are available at 335 MW thereafter.

-3- Coleson Cove unit 2 is available to NBEPC at 184 MW until October 31, 1985 due to participation sales. It is available at 310 MW thereafter.

-4- The capacity of Dalhousie unit 2 has been reduced by 20 MW to reflect the ownership of this portion by Maritime Electric Company of Prince Edward Island.

-5- Lepreau is available to NBEPC at 405 MW until October 31, 1991 due to participation sales. It is available at 635 MW thereafter.

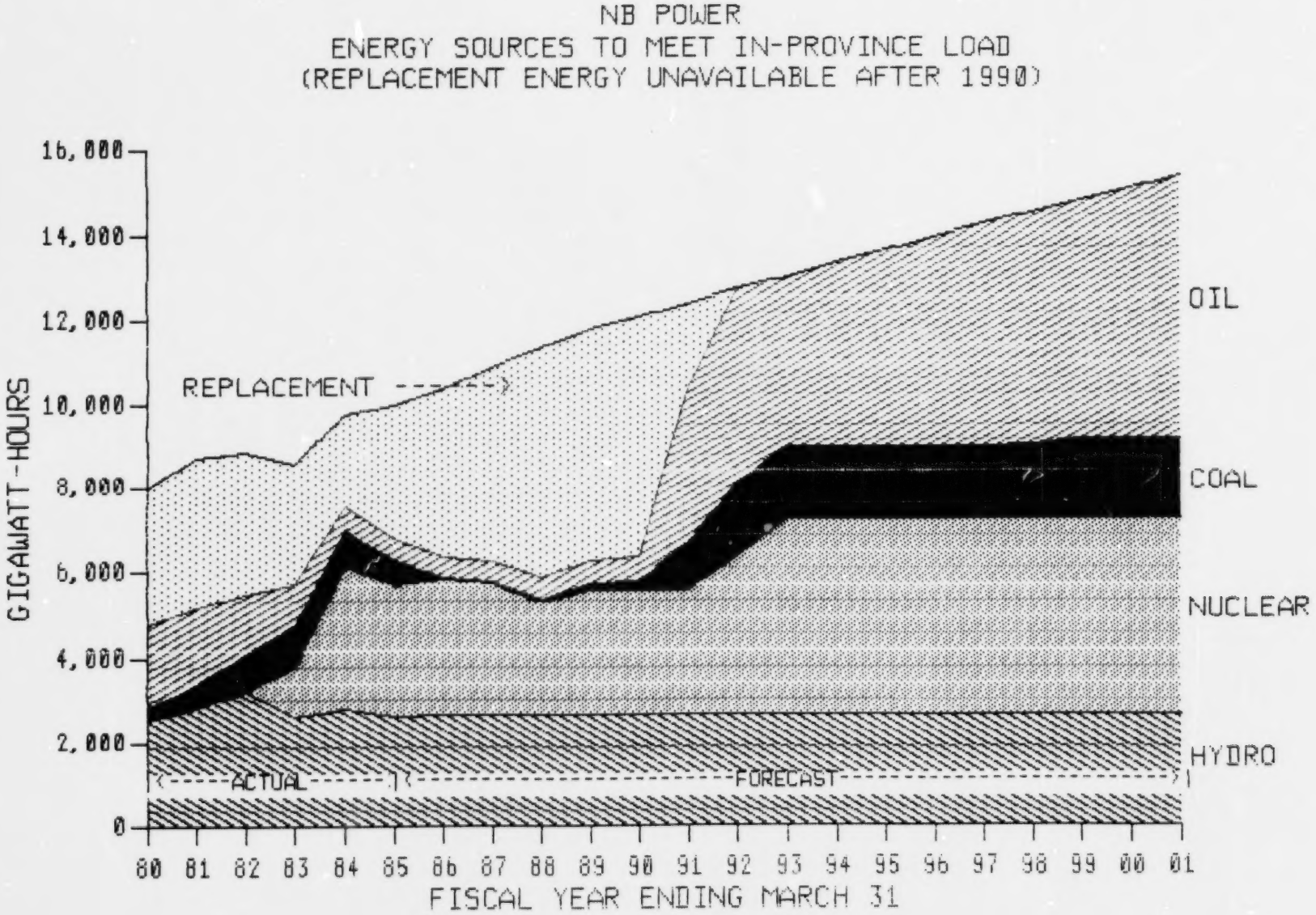

NB POWER
ENERGY SOURCES TO MEET IN-PROVINCE LOAD
(REPLACEMENT ENERGY UNAVAILABLE AFTER 1990)
GIGAWATT-HOURS
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
REPLACEMENT
OIL
COAL
NUCLEAR
HYDRO
ACTUAL
FORECAST
80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01
FISCAL YEAR ENDING MARCH 31

FIGURE II

V PLANNING CRITERIA

a) Reliability Criteria

In addition to supplying the annual energy requirement, the NB Power in-province generating capability, including any firm purchases, must be able to meet the peak power demand. Economy surplus energy is assumed not to be available for purchase at the time of peak demand. Since provision must be made for the partial loss of generating capability (ie. due to maintenance or breakdown) NB Power must maintain a minimum margin of reserve generating capability over and above the forecast peak.

NB Power employs the following two criteria in determining the required reserve margin:

i) A capacity related criterion pertaining to electrical generating capability at time of peak load which requires a reserve equal to the greater of the largest generating unit utilized on the NBEPC system or 20% of the system load. Thermal and hydro generation are considered fully available at rated capacity in the determination of this reserve margin.

ii) An energy related criterion pertaining to sustained electrical generating capability, in each hour of each month, which requires that the Maritime system (NB, NS, PEI) jointly be able to withstand the sustained loss of the largest unit on the interconnected system under conditions of historically low availability of hydro energy.

If the size of the largest unit is less than or equal to 10% of the interconnected system load, then each individual utility must maintain a proportionate share (based upon individual system load) of the reserve requirement. If, however, the size of the largest unit is greater than 10% of the interconnected system load, each utility maintains a reserve equal to the proportionate share of 10% of the interconnected load with the utility owning the largest unit responsible for the remainder. In order to calculate the reserve margin, thermal generation units are considered available at rated capacity while the hydro generation is reduced to the firm capacity which would be available for the hydro energy conditions considered. Under present conditions the 405 MW of Pt. Lepreau assigned to NB Power is the largest unit on the interconnected Maritime system.

NB Power is a member of the Northeast Power Co-ordinating Council (NPCC) one of the regional reliability councils of the North American Electric Reliability Council (NERC). NB Power adheres to the NPCC Generation Reliability Criterion. It is as follows:

> "Each area's generation capacity will be planned in such a manner that, after due allowance for scheduled maintenance, forced and partial outages, interconnections with neighboring areas, and available operating procedures, the probability of disconnecting non-interruptible customers due to generation deficiency, on the average, will be no more than once in ten years".

Analysis has indicated that, without resorting to any special or emergency operating procedures, the NB Power reliability criteria result in a probability of load loss which conservatively meets NPCC criterion. This good performance results primarily because of NB Power's network of interconnections with Hydro-Quebec, Nova Scotia and New England.

If firm purchase contracts are negotiated as one expansion option the influence on NB Power's reliability criteria will be reviewed to ensure that influence is fully represented and included.

b) Environmental Criteria

During the construction and operation of generation and transmission facilities, NB Power must, of course, adhere to the various applicable regulations of both federal and provincial statutes. These regulations can represent a very significant constraint with possible serious financial implications.

Further, as part of the consideration of any major generation or transmission development, NB Power conforms to the New Brunswick Environmental Impact Assessment Policy. This policy requires the preparation of an environmental impact assessment for major projects carried out by any provincial agency, department or crown corporation. In addition, for any projects with federal participation, the requirements of the Federal Environmental Assessment and Review Process (EARP) are followed on behalf of the relevant federal initiating agency. The environmental concerns of the National Energy Board are also addressed for any project involving the export of power.

VI LOAD AND RESOURCES REVIEW

In order to determine the magnitude and timing of generation expansion additions, it is necessary to first evaluate the ability of NB Power's resources to meet the in-province load. This calculation is commonly referred to as a "Load and Resources Review" [2].

The committed resources are comprised of the total monthly generation capabilities from existing generation, generation committed or under construction, and any firm purchases. Non-firm purchases of replacement energy are not considered. The monthly required load which must be met is made up of the total forecast system load plus a reserve margin.

A surplus or deficit in the capability to supply is determined based upon both the reserve for peak electrical capability (capacity) and the reserve for sustained electrical capability (energy).

a) Peak Electrical Capability Assessment

The required capacity reserve for peak electrical capability is added to the peak forecast load to determine the total peak load that must be met. This total load is compared with the sum of the committed supplies available from hydro, nuclear and thermal units to determine the surplus or deficit in generating capability. In doing this calculation all generating units (hydro, nuclear and thermal) are considered to be adequately maintained and available at their full net rated capability during the peak load period as given in Table I.

b) Sustained Electrical Capability Assessment

The required energy reserve for sustained electrical capability assesses the ability of the committed supplies to meet, during every hour of each month, the forecast load plus the required sustained reserve. For this assessment nuclear and thermal units are assumed available at full rated capacity 100% of the time during the peak load month of the year. Purchases of economy energy are assumed to be unavailable at the time of peak demand.

Hydro units, however, are limited to the monthly energies and seasonal storage energy given. These are the energies resulting from historic low hydro energy conditions and are equivalent to 95% probable river flows including effective regulation of existing storages.

The results of both the peak and sustained electrical capability assessment are given in Table II.

The details of the calculations to determine reserve requirements and the surplus/deficit are given in Appendix A for the peak month of January.

TABLE II
SUMMARY
FORECAST ELECTRICAL DEMAND VS GENERATING CAPABILITY
PERIOD 1985/86 - 1999/2000
(MEGAWATTS)

	PEAK ELECTRICAL CAPABILITY			SUSTAINED ELECTRICAL CAPABILITY		
Fiscal Year	Forecast Demand Plus Reserve (1)	Generating Capability	Surplus/ Deficit	Forecast Demand Plus Reserve 2	Generating Capability 3	Surplus/ Deficit
1985/86	2316	2945(4)	629	2173	2547(4)	374
1986/87	2411	2945	534	2261	2557	296
1987/88	2514	2945	431	2352	2575	223
1988/89	2608	2945	337	2424	2586	161
1989/90	2687	2945	258	2485	2597	112
1990/91	2764	2945	181	2544	2607	63
1991/92	3009	3175(5)	166	2833	2847(5)	14
1992/93	3071	3175	104	2890	2857	-34
1993/94	3130	3175	45	2945	2866	-79
1994/95	3184	3175	- 9	2993	2873	-120
1995/96	3251	3175	-76	3054	2883	-171
1996/97	3304	3175	-129	3102	2890	-211
1997/98	3358	3175	-183	3150	2899	-251
1998/99	3413	3175	-238	3199	2906	-293
1999/2000	3469	3175	-294	3248	2915	-334

NOTES: RELEVANT TO TABLE II

1. Reserve for peak electrical capability is set at 20 percent of forecast demand or the capacity of the largest unit whichever is greater.

2. Reserve for sustained electrical capability is the additional capability which is necessary to meet the forecast demand if the largest single source of generating capability relied on in the Maritime systems is out of service during periods of low river flows. The generating capability of hydro stations is adjusted to account for the limited energy available under the lowest expected hydro generating conditions.

3. Capability to meet sustained electrical demand increases by an average of 9 MW annually as increasing system demand permits more effective utilization of the installed hydro generation during peak loading periods.

4. Capability to meet both peak and sustained electrical demand increases in November 1985 by 400 MW with the return of the Coleson Cove participation sale.

5. Capability to meet both peak and sustained electrical demand increases by 230 MW in November, 1991 with the return of the nuclear participation sales.

VII OPTIONS FOR THE FUTURE

a) General

This section deals with alternative generation development options to meet the requirements of the NB Power system.

In order to ensure the availability of the most economic energy sources to meet the requirements, it is necessary to consider all forms of supply. This includes the high capacity factor generating sources to meet base load requirements as well as the low capacity factor types of sources to meet peak period loads. Analysis must be performed in order to arrive at the mix of these two types which best meets the varying daily, weekly, monthly and seasonal power system demands.

Analysis of NB Power's load and resource situation indicates that additional sources will be required to supply New Brunswick in-province energy deficiencies, as early as 1992. These deficiencies usually occurring during the peak load months of winter, can be supplied through energy purchase contracts over these peak periods each year. Additional firm generating capacity, if installed on or before 1992, can be used to alleviate these energy deficiencies. However, the potential for the implementation of small scale hydro units could also assist in meeting such requirements.

A summary of the options being considered is presented here.

b) Nuclear

Nuclear power has become an economical and environmentally acceptable means of supplying the high load factor (base load) requirements of a power system. There are, however, both economic and technical limitations to the amount of nuclear generation which a relatively small system can utilize. This has prompted renewed investigation of continued participation sales of least a part of the output of Point Lepreau 1. Such continued sales would benefit NB Power through continued reduction of financial risk associated with sustained failure of such a large unit. The revenue accruing from such sales could be invested in additional capacity from such technologies as circulating fluidized bed combustion utilizing fuels and resources native to New Brunswick.

Early development of a second nuclear unit could be undertaken with the financial support of the Federal Government and unit participation by other utilities, for an extended period of time. This unit would be constructed primarily to satisfy export markets during the early years of operation resulting in economical power for New Brunswick in future years.

c) Coal-Fired Thermal Generation

The uncertainty in both the price and security of supply of oil as well as the new technologies relating to the combustion of coal has placed a renewed emphasis on coal utilization.

The known reserves of native NB coal indicate an ample supply of coal to fuel in the order of 200 MW of additional coal-fired thermal generation. The evolving new fuel combustion technologies may represent the only means to utilize this resource in conjunction with native oil shale and/or limestone in a manner consistent with environmental guidelines.

The expected long-term price competitiveness of environmentally acceptable imported coal fuel in comparison with oil has led to consideration of development of new conventional coal-fired stations. Such stations offer price stability, through long term contracts for guaranteed supply of environmentally acceptable low-sulfur coal to meet emission guidelines.

d) Conversion of Oil-Fired Thermal Generation

Conversion of existing oil-fired generating units to burn fuel such as coal or natural gas is being examined as a means of displacing oil-fueled generation. Studies have been undertaken and continue to fully examine the potential benefits to New Brunswick consumers of various conversion alternatives.

i) Coal Conversion

Conversion of units to burn coal involves major capital expenditures for boiler modifications or replacement and for the equipment necessary to handle and process the coal.

Three phases of a proposed three phase feasibility study into the conversion of the Coleson Cove station to coal have been completed. These studies were performed in

cooperation with the Federal Government under the off-oil program. Results to date have demonstrated the overall technical and economic feasibility of the conversion. Agreement has been reached with the Federal Department of Energy, Mines and Resources (EMR) covering the preliminary engineering portion of the third phase of the study. Work began April 1, 1984 and was completed in 1985. Figure III illustrates the overall system generation dispatch to meet in-province energy requirements if Coleson Cove is converted.

The original boiler designs for Courtenay Bay Unit No. 1 and Dalhousie Unit No. 1 included some basic provisions for possible future conversion to coal. This will be the subject of further study.

Consideration must also be given to environmental impacts of any such conversion and to the effect and costs of emission controls.

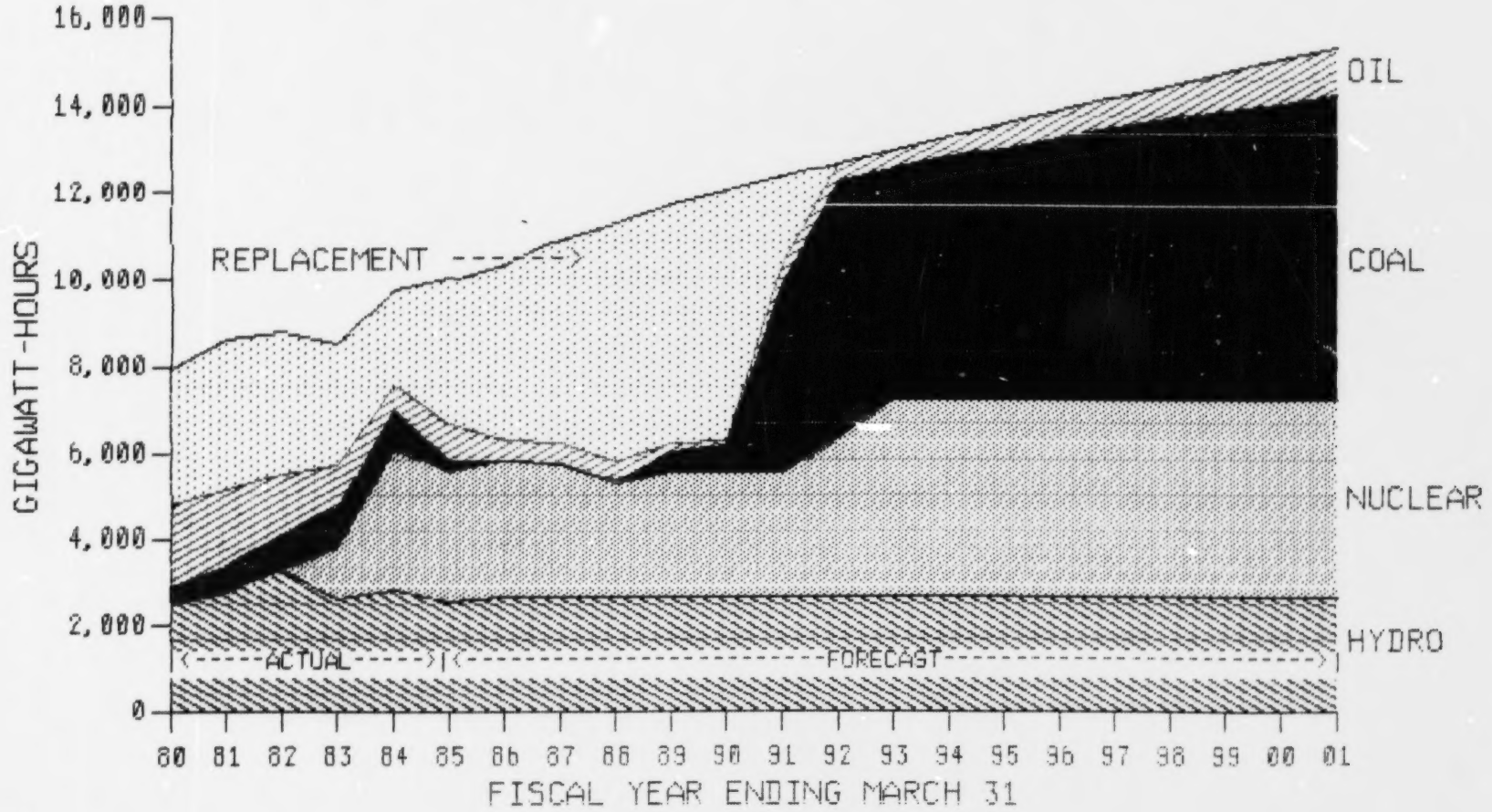
ii) Coal-Water Mixture Demonstration

A project to determine the feasibility of using a coal-water mixture (70% coal, 29% water, 1% chemical additives) as a fuel oil replacement was undertaken at the Chatham Generating Station in cooperation with Energy, Mines and Resources Canada (EMR) and the Cape Breton Development Corporation (CEDC). The fuel mixture, known as "Carbogel", was manufactured by CBDC using a process developed by Swedish Researchers.

As a result of the combustion test program many technical uncertainties have been resolved with some further work required.

Additionally, EMR is looking at the conversion of a large full-scale unit and have identified Dalhousie No. 1 unit as a potential candidate. NB Power is currently involved in preliminary technical and economic project assessment to identify costs and degree of support available from EMR.

NB POWER
ENERGY SOURCES TO MEET IN-PROVINCE LOAD
(REPLACEMENT ENERGY UNAVAILABLE AFTER 1990)
COLESON COVE CONVERTED TO COAL-FIRED OPERATION



80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01

FISCAL YEAR ENDING MARCH 31

FIGURE III

iii) Circulating Fluidized Bed Demonstration Project

In December, 1983, NB Power and the Federal Department of Energy, Mines and Resources, signed a two phase agreement aimed at developing a new coal combustion technology. This technology, if successful, would ensure continuing utilization of New Brunswick's high sulphur coal in an environmentally acceptable manner.

The first phase involved a preliminary technical and economic assessment of the feasibility of incorporating a circulating fluidized bed combustor into the Chatham No. 2 plant. This first phase of the study was completed in June, 1984 and a decision to proceed to a phase II demonstration unit was announced August 28, 1984. Construction of the $33 million project,funded by the Federal Government, will be completed in 1986. Evaluation of the technology, which should reduce sulphur and nitrogen oxide emissions by up to 90%, will require an additional two years.

The fluidized bed combustor is intended to utilize a mixture of native coal alone or in combination with oil shale. It can also utilize limestone as an additive to reduce sulphur emissions.

Since these co-combustion fuels are obtainable in the province, a successful demonstration will ensure that employment in the coal industry would be sustained and could be expanded with further potential for the development of an industry to supply the oil shale if it is used in the co-combustion process.

In parallel with our Chatham project, the Nova Scotia Power Corporation are conducting a preliminary design study for a 150 MW "circulating" fluidized bed unit and NB Power will have full access to their results. This design study project should be completed in early 1987, following an evaluation of the initial results from Chatham.

The largest "circulating" fluidized bed unit which is currently under construction is being built by a Colorado utility and will supply steam to four turbine/generators totalling 110 MW electric. This demonstration project is currently scheduled for startup in late 1987, approximately one year after NB Power's Chatham unit commences

operation.

Assuming that all of these activities achieve their stated objective, the following conclusions would appear to be reasonable:

"Circulating" fluidized bed technology for conventional fuels should be demonstrated on a utility scale by 1986 in West Germany and 1988 in North America. In concert with this, the Chatham fuel demonstrations should enable NB Power to make a decision on a specific coal-fired fluidized bed unit for the province by early 1988. Allowing for a 4 to 5 year design and construction period this would put a unit in-service in the 1992/93 time frame depending upon the site chosen.

The Chatham demonstration project is a direct result of the Federal Department of Energy, Mines and Resources' agreement to the use of the Chatham station to demonstrate emerging energy technologies appropriate to New Brunswick resources. The Chatham station is an ideal size for demonstration programs and can be made available for such testing purposes because of its age, relatively small size and lower capacity factor operation.

iv) Venezuelan Bitumen

Venezuelan bitumen, a very dense oil-based fuel, represents a potentially attractive alternative or adjunct to coal conversion. While conversion costs would be much lower than those for coal conversion, bitumen has potential drawbacks in areas such as technical viability, environmental acceptability, and contractual and single source of supply risks, all of which would have to be satisfactorily resolved.

v) Natural Gas Conversion

Any decision to have natural gas available to the Maritimes makes the use of natural gas a replacement fuel for imported oil a possibility. While the burning of natural gas as a fuel for thermal plants is not favoured by either the producing provinces or the Federal Government as a long term commitment, there is a clear acceptance of the role it can fulfil in the development of a viable market in the short term. The Coleson Cove plant has design provisions consistent with natural gas fuelling. Other plants such as Courtenay Bay could be converted with additional engineering design modifications. This is particularly

interesting for Unit No. 2 at Courtenay Bay which is utilized for process steam and energy for Rothesay Paper Company. Such a conversion would also provide a security advantage in that the fuel is a Canadian resource.

This alternative will be further developed as the supply situation clarifies as to date of availability in the province, and probable cost and supply structures.

e) Hydraulic Generation

i) Tidal Power Generation

Development of tidal generation in the upper reaches of the Bay of Fundy has been the subject of considerable study.

A major study under the direction of the Atlantic Tidal Power Programming Board concluded in 1969 that development of tidal power was technically, but not economically, feasible under the then prevailing circumstances.

A major review of tidal power development in the Bay of Fundy was completed in 1976 by the Governments of Canada, Nova Scotia, and New Brunswick. The study concentrated on 3 sites; a 3800 MW site at Cobequid Bay, Nova Scotia, between Economy Point and Cape Tenny, a 1085 MW site at the Mouth of Cumberland Basin, adjoining both New Brunswick and Nova Scotia and a 1500 MW site at the Mouth of Shepody Bay in New Brunswick. The Review Report identified the Cobequid Bay (Minas Basin) and Cumberland Basin sites as being of equal economic viability with preference being given to the smaller Cumberland Basin site. Because of the tremendous financial burden of a tidal development, particularly during its early years of operation, such a project would require heavy involvement by the Federal Government.

The Fundy Tidal Power Review Board recommended additional studies on the preferred site at the Mouth of Cumberland Basin. This site would encompass both New Brunswick and Nova Scotia whereas the Minas Basin site would be entirely within the province of Nova Scotia.

In 1982 Nova Scotia and the Federal Government completed an update of costs and economic viability of tidal power in the Bay of Fundy with specific reference to the Minas Basin site which is located

wholly in the Province of Nova Scotia. This "Update 1982" concludes that Tidal Power economic viability has improved since the 1976 study.

Interest in tidal power has continued and a study is presently underway. The Federal Government and the Nova Scotia Tidal Power Corporation commissioned ALCAN, a private company with a strong background in Energy Resources analysis, to complete a study on the economic viability of the Cumberland Basin site. They are also examining the marketability of tidal power in the New England States.

Nova Scotia, with the assistance of a Federal Government grant, has completed construction of a 20 MW tidal power demonstration plant at Annapolis. This unit is now operating on the Nova Scotia system and should demonstrate the application of a specific type of generating unit in a tidal environment.

ii) Other Hydraulic Generation

The overall long term potential for development of hydraulic generation within the province on the Saint John River system in New Brunswick was analyzed in a study carried out for NB Power in 1975.

Since that time a number of more detailed investigations have been undertaken in order to determine what projects might be undertaken to assist in meeting forecast requirements and to further reduce dependency on imported oil. These are as follows:

1. A project which has been given consideration is the potential Green River pumped storage project. The development would be located about two miles upstream of the present City of Edmundston owned Second Falls hydro development on the Green River. It would create a 17 mile long lake and would have an annual energy generating capability of some 130,000 MWh from two 80 MW generating units.

The development, as proposed, would operate as a seasonal storage. Water stored during the spring freshet would be released during the low flow, high system electrical demand periods of December through March. The development would also operate year round as a daily cycle pump storage facility whereby the units would generate power for about two or more peak load hours of the day. The water

released during the generation mode would be pumped back from the lower (Second Falls) reservoir during the night. Low cost nuclear energy could be used for such pumping requirements.

Green River development continues to be looked at as a project for the future but the exact date will depend on relative economics as compared to other development opportunities and on the extent of load growth actually experienced.

2. A project of interest to NB Power because of the large amount of energy associated with it is Grand Falls redevelopment. Redevelopment with no change in the headpond operating level and an added plant with an installed capacity of up to 300 MW could be developed to produce an average annual energy output of 386,000 MWh. With a 20 foot increase in headpond level the same installed capacity could produce an average annual energy output of 655,000 MWh. A large percentage of the additional energy would be generated during high river flow periods.

Future consideration of this development would be enhanced by the opportunity to sell peaking generation to export market areas. Such peaking sales would help to offset negative cash flows which would, under current circumstances, exist in the early years of operation of such a development due to its heavy capital requirement.

3. Studies to date have identified a number of small hydro sites which have the potential to contribute to fuel displacement while keeping NB Power abreast of the state of the art in such small scale developments. Two such sites will be identified and studied for potential development in the 1990-2000 time frame.

4. Other hydraulic development potentials which remain of interest to NB Power are:

- Development of the Morrill site (between Beechwood and Grand Falls) with an installed capacity of approximately 140 megawatts.

- The possibility of pumped storage operation at the existing Tobique Plant which would be related largely to better utilizing overall system generating capability.

- Development of new reservoirs and increasing the size of existing ones to increase energy

production during low river flow periods.

- Development of hydro and/or pumped storage at other potential sites throughout the province.

These hydro development possibilities continue to be assessed both on their ability to supply the short duration, electrical demand requirements of the power system and on their ability to displace the oil fuel which would otherwise be required. It becomes a matter of balancing the economic and development effects against the opportunity to secure an energy source to further displace oil dependency.

f) Purchases

Purchases from interconnected utilities can provide a major source of energy not only to replace thermal energy but, under the right conditions, could also offer an opportunity to defer construction of generation installations until larger more economic projects can be undertaken. Such purchases depend on the availability of surplus generation from the selling utilities. In order to take advantage of any opportunities, on-going liaison is maintained with neighbouring utilities.

The second interconnection with Hydro-Quebec has recently been placed in full commercial operation. With the completion of this project, NB Power will be able to import an additional 500 MW from Hydro-Quebec. This is one of the most important projects of the decade for New Brunswick and the Maritimes.

In the past, surpluses available from New England and Nova Scotia have tended to be more expensive than Hydro Quebec energy since they came primarily from gas turbines and smaller less efficient thermal units. These were therefore predominantly useful only for meeting short term energy deficiencies in the winter months or in an emergency. However, with the recent installation of additional coal-fired thermal generation in Nova Scotia, NB Power has purchased surplus coal-produced energy from Nova Scotia and utilized it not only for displacement of oil-fired generation on the NB Power system but also for sale using the interconnections.

The benefits of interruptible energy purchases and sales are not secure because the transactions

occur over very short time periods and may or may not be possible on an ongoing basis in the longer term. NB Power may be able to eliminate much of this uncertainty by contracting energy purchases and sales in guaranteed quantities over longer periods of time. Such an approach entails some risk, however, since the guaranteed energy quantities must be taken or supplied notwithstanding the fact that future circumstances could render such action undesirable. On balance, given increased competition in interconnection markets and the high degree of importance of energy transaction benefits for New Brunswick, a move to try to ensure more guaranteed quantities and long term contracts is seen to be advisable at this time.

There appears to be a strong and attractive market developing for capacity plus energy sales into New England beginning in the early to mid-1990's and into PEI before 1990. NB Power could be well poised to capitalize on these opportunities if it has available capacity for sale. Coal conversion at Coleson Cove could create export sales opportunities. The probability of a high value market opportunity for capacity further suggests that NB Power should probably pursue an aggressive strategy for adding new capacity to serve New Brunswick requirements in the next 15 years. The utility and its customers might well be better off if construction of new generating units is advanced to take advantage of the future export market potential. Pre-building generating facilities specifically for export purposes is also a potentially attractive option. This is the concept behind the Lepreau II project (discussed below). A third way to benefit from the market potential would be to purchase capacity-plus-energy packages from one neighbouring utility for sale at a higher price to another.

Early indications are that extended, long term capacity plus energy sales from the highly successful Point Lepreau I unit may be possible at much higher prices than the existing, shorter term sales which were negotiated up to two years before the unit received an operating license (the first 630 MW CANDU in-service). Ths could prove to be an even more attractive strategy if a significant portion of th extended sale profits is used to fund the cost of building replacement generating capacity (e.g. a circulating fluidized bed unit). Such a strategy could prove highly profitable and it would promote economic activity to construct

replacement generating capacity. An extend Lepreau I sale would also continue to process of reducing. NB Power's exposure to the financial and operational risks associated with the large 635 MW single unit nuclear facility, at least until a second unit becomes available for a shared reliability arrangement to achieve this objective.

g) Combustion Gas Turbine Generation

Gas turbines in general are characterized by low capital cost, high operating cost and short acquisition and installation times. These turbines are, therefore, primarily suitable for low capacity factor operation either as reliable sources for supplying short-term, or unpredicted, peak demands or for meeting an area peaking requirement where an economic deferral of transmission facilities can be achieved.

In the New Brunswick system, their possible application has been largely considered as an alternate to hydro peaking capability or for voltage support and transmission deferrals. The latter was the case for the existing Moncton Gas Turbine. Since New Brunswick has a substantial hydro peaking capability, both developed and undeveloped, no additional specific applications have been found economic in meeting NB Power's requirements.

h) Alternate Energy Sources

NB Power continues to keep abreast of the latest technology in the use of alternate fuels for electrical generation. Activity in this area to date has largely been to ensure a current knowledge of alternative energy sources such as wood, solar collectors, passive heat collection, ground water sources, and wind generation, etc.

The circulating fluidized bed boiler to be built at the Chatham Plant, will be capable of burning a wide range of fuels. Initially, the material handling system will be designed for coal, oil shale and limestone. However, provision will be made to accommodate the future addition of equipment which could handle alternate fuels such as peat, waste wood, and petroleum coke, either for energy generation or as an alternate fuel testing facility.

i) Load Management

"Load Management" is a term that means different things to different people. In the context of this document it refers to efforts to manage customer load as seen from the utility side of the electric meter. Supplying energy in the night during the "off-peak" period can affect operational economies because of increased efficiency and utilization of the thermal generators to meet this portion of the load. Shifting a portion of the peak load to a convenient time where it can be more easily supplied may lower both the peak and sustained electrical demand. Depending upon the nature of the load being supplied, and the generating system supplying it, such load shifting practices can have a beneficial impact on generating costs and requirements for future generation.

NB Power has, for many years, offered interruptible energy to major industries in the province which have their own generation and have the capability of utilizing interruptible energy by reducing their own generation. This has had a beneficial affect on costs for both the utility and the industries.

NB Power has, on occasion, examined the feasibility of shifting load from the peak to the off-peak period for the benefit of both NB Power and any affected customers. This type of load management technique has beneficial affects primarily to systems with predominantly thermal generation. NB Power, however, with its plentiful supply of peaking hydro capability, effectively levelizes the thermal generation requirement over a significant portion of the day. Shifting load from the peak period would result in some re-scheduling of the hydro to cover the latered peak. However, the resulting load supplied by the thermal generation and the sustained electrical capability needs would remain relatively unchanged.

NB Power continues to review means of more accurately predicting the "nature" of loads and hence of better predicting future requirements both with and without load management.

j) Energy Conservation

Energy conservation continues to be a major concern of NB Power both in terms of its own operations and in its efforts to assist consumers

in practical conservation effects. A low interest loan program promoting the installation of improved insulation in homes is administered by NB Power for the Provincial Government. As well, NB Power participated in the administration of the Canada Home Insulation Program which ended March 31, 1985. Monitoring and analysis continues of more energy efficient buildings such as the Rothesay and Shediac District Offices as well as an energy efficient demonstration home in Nasonworth outside Fredericton. In addition, several new energy efficient homes are being monitored.

NB Power also maintains through its field offices, with specialized back-up at its Head Office, an ability to advise consumers directly on the availability of the various support programs, to answer questions on NB Power's marketing program, and to provide direct homeowner advice on conservation and conversion concerns.

The impacts of conservation have been considered in NB Power's official 1985 Load Forecast.

k) Waste Heat Utilization

(i) Mactaquac

As part of its ongoing efforts to maximize the utilization of waste heat from generating plants, NB Power and the Federal Department of Fisheries and Oceans have entered into a joint venture to raise juvenile salmon at Mactaquac dam. This project, which uses warm water available from the turbine bearing and stator cooling systems to accelerate the growth of young salmon, is the only production aquaculture facility in the world using warm water from a hydro electric station auxiliary systems.

The new facility will play a financially attractive major role in the salmon enhancement program on the Saint John River.

(ii) Surface Heated Greenhouse

The utilization of waste heat from a thermal power plant offers an opportunity to reduce greenhouse operating costs, by replacing a portion of the fuel oil with heat from the effluent. A recently completed pilot project at the Grand Lake Generating Station involved

surface heating by cascading warm water over the outside surface.

During the demonstration period, it was found that the heating costs of the surface heated greenhouse were approximately 33% less than those of conventionally heated greenhouse.

The demonstration was jointly supported by the Canadian Electrical Association, the New Brunswick Energy Secretariat, N.B. Coal and NB Power.

VIII PRESENTATION OF A FEASIBLE GENERATION EXPANSION PLAN

The prime objective of NB Power is to provide a reliable supply of electricity at the lowest possible cost. However, another very important role requires careful consideration to derive not only economic but also flexible plans; that is, to be responsive and instrumental in provincial economic development.

With this in mind, NB Power's corporate generation planning approach is based, not on any rigid commitment to expansion, but rather on being ready to adjust to rapidly changing conditions, and the ability to meet a wide range of demand. The varying economic conditions of the past few years, the ever-mindful need to be cognizant of the extent of our use of fossil fuels, and our strategic position in a competitive market next to a source of surplus renewable hydro energy on the one hand with ready markets on the other, make the decision making process related to a flexible generation expansion plan a particularly demanding one.

In full consideration of these constraints and with the knowledge of the alternative options presented in the previous section, the following represents two feasible expansion plans which are being considered to meet requirements to the year 2000: 1) A predominant Coal Plan and 2) a predominant Nuclear Plan

1. Coal Plan

1985-1990	Conversion of Coleson Cove from oil-fired to coal-fired operation
1985-1990	Conversion of Dalhousie Unit 1 from oil-fired to coal-water mix or alternatively to Coal-Fired operation.
1991-2005	Continued Participation Sales from Point Lepreau 1
1992	Fluidized Bed Combustion Unit(200 Megawatts)
1998	Conventional Coal Fossil-Fired Generating Unit (350 Megawatts)
1990-2000	Development of 2 Small Scale Hydro Sites Total 20 Megawatts

The impact of this expansion plan on the energy sources to meet in-province demands is shown in Figure IV for the period 1985-2000.

During the 15 year outlook period from 2000-2015, the following represents an appropriate expansion plan to

meet NB Power's extrapolated in-province demand requirements. Of course, these are projected with much less certainty because of the time period involved.

2002 Conventional coal Fossil-Fired Generating Unit (350 Megawatts)

2009 Point Lepreau 2 (635 Megawatts)

Nuclear Plan

1985-90 Conversion of Coleson Cove from oil-fired to coal-fired operation.

1985-90 Conversion of Dalhousie Unit 1 from oil-fired to coal-water or alternatively to coal-fired operation.

1991-2005 Continued participation sales from Point Lepreau 1

1992 Fluidized Bed combustion Unit (200 MW)

1995 Point Lepreau II

The following should be noted:

(1) Decisions as to the conversion of Coleson Cove have not yet been taken subject to completion of technical and environmental reviews.

(2) The feasibility, timing, cost and benefit of conversion of Dalhousie Unit 1 to coal-water mix fuel is under review.

(3) The exact size and duration of any possible extended participation sales from Point Lepreau 1 will depend on planning and marketing efforts presently underway.

(4) The development of a full-scale fluidized bed combustion unit depends on the experience gained during the operation of the demonstration unit presently being built at Chatham.

(5) The development of new conventional coal fired generation appears to be an economic alternative for the late 90's.

(6) The need, timing, cost and benefit for possible development of small scale hydro is under continuing review.

As stated previously, the generation planning process has been, and continues to be, one of annual review and scrutiny, with the objective of maintaining a flexible strategy to meet evolving requirements. A combination of coal and nuclear plant additions might well prove to be the most practical option to meet the future needs of N.B. Power customers.

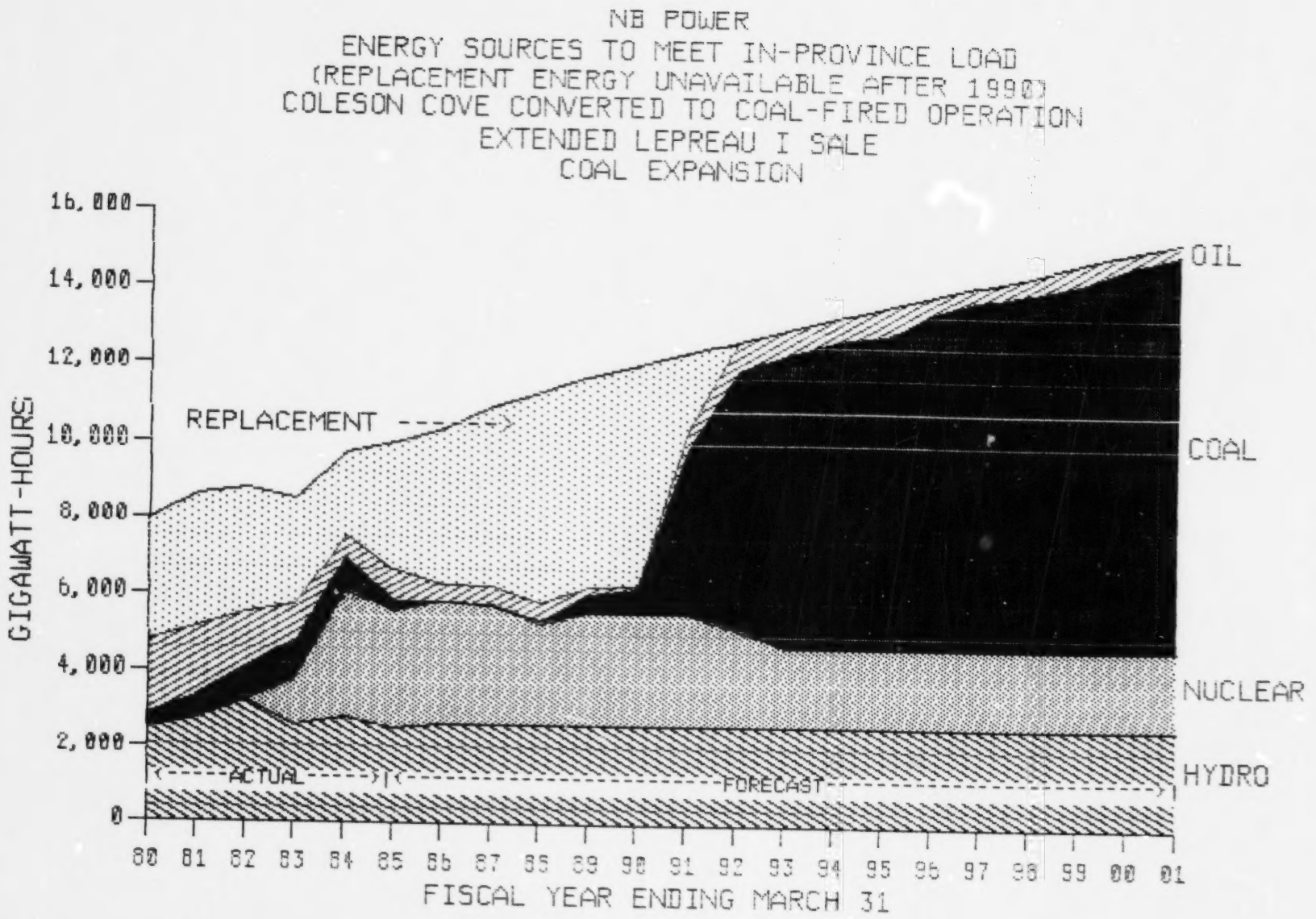

NB POWER
ENERGY SOURCES TO MEET IN-PROVINCE LOAD
(REPLACEMENT ENERGY UNAVAILABLE AFTER 1990)
COLESON COVE CONVERTED TO COAL-FIRED OPERATION
EXTENDED LEPREAU I SALE
COAL EXPANSION
GIGAWATT-HOURS
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
REPLACEMENT
OIL
COAL
NUCLEAR
HYDRO
ACTUAL
FORECAST
80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01
FISCAL YEAR ENDING MARCH 31

FIGURE IV

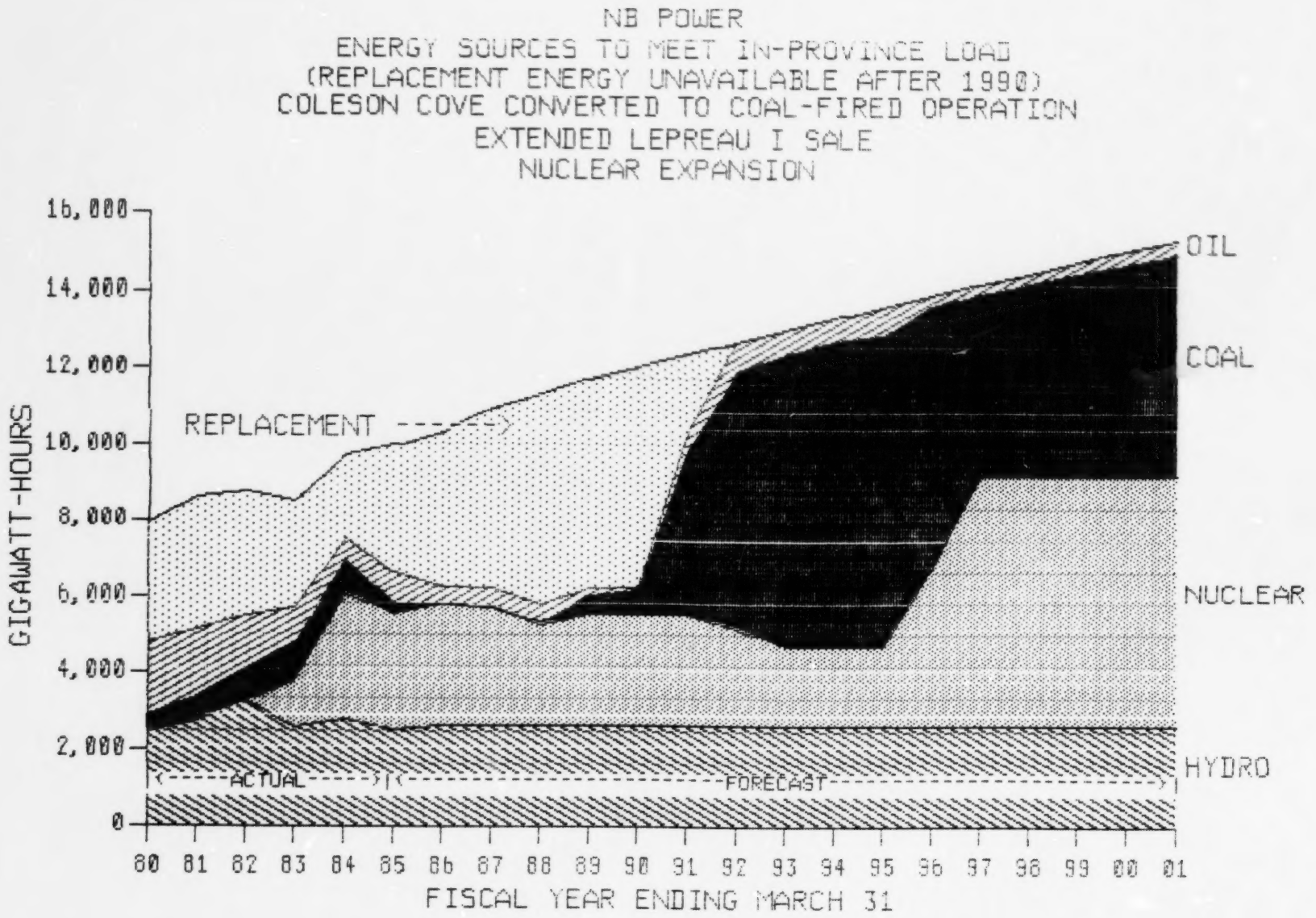

NB POWER
ENERGY SOURCES TO MEET IN-PROVINCE LOAD
(REPLACEMENT ENERGY UNAVAILABLE AFTER 1990)
COLESON COVE CONVERTED TO COAL-FIRED OPERATION
EXTENDED LEPREAU I SALE
NUCLEAR EXPANSION
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
GIGAWATT-HOURS
REPLACEMENT
OIL
COAL
NUCLEAR
HYDRO
ACTUAL
FORECAST
80 81 82 83 84 85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01
FISCAL YEAR ENDING MARCH 31

FIGURE V

IX CONCLUSIONS

In spite of much higher historical growth rates, in-province load growth in the 1985-2000 period is forecast to average 2.8% annually for energy sales and 2.9% annually for peak capacity requirements. New generating facilities may have to be in operation to satisfy reserve requirements for in-province loads as early as 1992.

Based upon the in-province load forecast, about 300 MW of additional generating capacity will have to be in-service by the year 2000. If incremental additional annual load growth increases by as little as 1% per year compared to the forecast new capacity requirements would increase to about 700 MW by the year 2000. These estimates do not consider any capacity-related export sales which could also lead to new or advanced capacity requirements.

The ongoing availability of significant interconnection benefits will be a major issue for the Commission in the 1985-2000 time frame. On the power purchase side, Hydro Quebec's energy surpluses are subject to a very broad range of uncertainty. Furthermore, increasing competition for Hydro Quebec energy supplies may be expected among New Brunswick, New England, New York and Ontario in coming years. In light of this competition, and given the importance of energy transaction benefits for New Brunswick, NB Power will strive to ensure more guaranteed quantities long term contracts.

On the interconnection sales side, new challenges may also be expected for NB Power in coming years. Lower oil prices and reduced oil utilization in New England are putting pressure on margins for energy sales into the region. This situation is expected to persist for at least the remainder of the 1980's. Energy sales potential thereafter will depend very much upon system development alternatives actually implemented by NB Power in coming years. The regulatory climate in New England is currently thwarting capital investment by utilities in the region and it is anticipated that attractive opportunities for capacity and energy sales in the 1990's will result. The probability of these opportunities emphasizes the need for all development options, including new capacity, conversions and capacity plus energy purchase contracts. It may even advance the need for new capacity or purchase packages to take advantage of export market potential.

Within the Maritimes, an aggressive coal development plan in Nova Scotia is expected to continue to limit energy sales opportunities for NB Power. Prince Edward Island on the other hand should continue to offer a steady market. The Island will have to purchase a firm capacity/energy package, probably before the end of this decade.

Fuel price trends will have a dramatic effect upon NB Power and its development. Of particular concern will be the absolute levels of oil prices and the evolving differential between coal and oil prices. Oil prices are expected to decline in real terms until the early 1990'S. This would temporarily relieve no power of the cost pressure which has accompanied the massive oil price rises of the last 11 years but could be substantially offset by reduced export earnings.

The spread between coal and oil fuel prices is expected to narrow even more in the near term. Later in the 1990's, the price spread should widen considerably as oil prices are expected to resume their upward spiral. The economic attractiveness of conversion of existing oil-fired generating units to have coal burning capability is directly related to this price spread. Since major unit conversions such as the one planned for Coleson Cove Generating Station take 3-4 years to fully implement, it may well prove necessary and appropriate to commence conversions even while the price spread is narrowing.

Generation expansion planning from now until the end of the century must, of necessity, consider conversions, new capacity, and purchase/sales in a manner which ensures planning flexibility to meet changing requirements while minimizing the cost of any unforeseen changes.

APPENDIX A

The attached Tables III, IV and V show the detailed calculations to derive the summary results of Table II in the body of the report.

Table III shows the calculation of required annual reserve using the criteria outlined in Section V of the body of the report.

Tables IV and V show the calculation of surplus or deficit using the procedure outlined in Section VI of the body of this report.

TABLE III

LOAD & RESOURCES REVIEW

RESERVE REQUIREMENTS

FISCAL YEAR	FORECAST PEAK DEMANDS N.B. (MW)	N.S. (MW)	P.E.I. (MW)	TOTAL (MW)	N.B. LOAD AS A PERCENT (%)	10% OF TOTAL (MW)	LARGEST UNIT (MW)	EXCESS OF LARGEST UNIT (MW)	RESERVE SUSTAINED PEAK CAP. (MW)	CAP. (MW)
	1	2	3	4=(1+2+3)	5=(1/4)*100	6	7	8	9	10
1985-1986	1911.	1317.	110.	3338.	57.2	334.	405.	71.	262.	405.
1986-1987	2006.	1384.	114.	3504.	57.2	350.	405.	55.	255.	405.
1987-1988	2102.	1437.	117.	3656.	57.5	366.	405.	39.	250.	412.
1988-1989	2180.	1487.	121.	3788.	57.6	379.	405.	26.	244.	428.
1989-1990	2246.	1534.	125.	3905.	57.5	391.	405.	15.	239.	441.
1990-1991	2310.	1579.	129.	4018.	57.5	402.	405.	3.	234.	454.
1991-1992	2374.	1624.	133.	4131.	57.5	413.	635.	222.	459.	635.
1992-1993	2436.	1669.	136.	4241.	57.4	424.	635.	211.	455.	635.
1993-1994	2495.	1714.	140.	4349.	57.4	435.	635.	200.	450.	635.
1994-1995	2549.	1765.	144.	4458.	57.2	446.	635.	189.	444.	635.
1995-1996	2616.	1818.	148.	4582.	57.1	458.	635.	177.	438.	635.
1996-1997	2669.	1872.	152.	4693.	56.9	469.	635.	166.	433.	635.
1997-1998	2723.	1927.	156.	4806.	56.7	481.	635.	154.	427.	635.
1998-1999	2778.	1984.	160.	4922.	56.4	492.	635.	143.	421.	635.
1999-2000	2834.	2044.	164.	5042.	56.2	504.	635.	131.	414.	635.

8=7-6 ONLY WHEN 7 IS LARGER THAN 6, OTHERWISE 8=0.0

9=7+5 ONLY WHEN 7 IS SMALLER THAN 6, OTHERWISE 9=(6+5)+8

10=0.2*A ONLY WHEN 7 IS SMALLER THAN 10, OTHERWISE 10=7

A=NB PEAK LOAD - NON FIRM SALES

TABLE IV

LOAD & RESOURCE REVIEW

** SUSTAINED ELECTRICAL CAPABILITY CRITERION **

(MONTH OF JANUARY)

FISCAL YEAR APR/MAR	FORECAST LOAD MW	REQ'D RESERVE MW	TOTAL LOAD MW	THERMAL CAP MW	HYDRO CAP MW	GROSS NUCLEAR CAP MW	NUCLEAR PART.OR FUEL REPL MW	NET NUCLEAR CAP MW	TOTAL RESOURCE MW	SURPLUS/ DEFICIT MW
1985/1986	1911.	262.	2173.	1657.	485.	635.	230.	405.	2547.	374.
1986/1987	2006.	255.	2261.	1657.	495.	635.	230.	405.	2557.	296.
1987/1988	2102.	250.	2352.	1657.	513.	635.	230.	405.	2575.	223.
1988/1989	2180.	244.	2424.	1657.	524.	635.	230.	405.	2586.	161.
1989/1990	2246.	239.	2485.	1657.	535.	635.	230.	405.	2597.	111.
1990/1991	2310.	234.	2544.	1657.	545.	635.	230.	405.	2607.	63.
1991/1992	2374.	459.	2833.	1657.	555.	635.	0.	635.	2847.	14.
1992/1993	2436.	455.	2891.	1657.	565.	635.	0.	635.	2857.	-34.
1993/1994	2495.	450.	2945.	1657.	574.	635.	0.	635.	2866.	-79.
1994/1995	2549.	444.	2993.	1657.	581.	635.	0.	635.	2873.	-120.
1995/1996	2616.	438.	3054.	1657.	591.	635.	0.	635.	2883.	-171.
1996/1997	2669.	433.	3102.	1657.	598.	635.	0.	635.	2890.	-211.
1997/1998	2723.	427.	3150.	1657.	607.	635.	0.	635.	2899.	-251.
1998/1999	2778.	421.	3199.	1657.	614.	635.	0.	635.	2906.	-293.
1999/2000	2834.	414.	3248.	1657.	623.	635.	0.	635.	2915.	-334.

TABLE V

LOAD & RESOURCE REVIEW

** PEAK ELECTRICAL CAPABILITY CRITERION **

(MONTH OF JANUARY)

FISCAL YEAR APR/MAR	FORECAST LOAD MW	REQ'D RESERVE MW	TOTAL LOAD MW	THERMAL CAP MW	HYDRO CAP MW	GROSS NUCLEAR CAP MW	NUCLEAR PART.OR FUEL REPL MW	NET NUCLEAR CAP MW	TOTAL RESOURCE MW	SURPLUS/ DEFICIT MW
1985/1986	1911.	405.	2316.	1657.	883.	635.	230.	405.	2945.	629.
1986/1987	2006.	405.	2411.	1657.	883.	635.	230.	405.	2945.	534.
1987/1988	2102.	412.	2514.	1657.	883.	635.	230.	405.	2945.	431.
1988/1989	2180.	428.	2608.	1657.	883.	635.	230.	405.	2945.	337.
1989/1990	2246.	441.	2687.	1657.	883.	635.	230.	405.	2945.	258.
1990/1991	2310.	454.	2764.	1657.	883.	635.	230.	405.	2945.	181.
1991/1992	2374.	635.	3009.	1657.	883.	635.	0.	635.	3175.	166.
1992/1993	2436.	635.	3071.	1657.	883.	635.	0.	635.	3175.	104.
1993/1994	2495.	635.	3130.	1657.	883.	635.	0.	635.	3175.	45.
1994/1995	2549.	635.	3184.	1657.	883.	635.	0.	635.	3175.	-9.
1995/1996	2616.	635.	3251.	1657.	883.	635.	0.	635.	3175.	-76.
1996/1997	2669.	635.	3304.	1657.	883.	635.	0.	635.	3175.	-129.
1997/1998	2723.	635.	3358.	1657.	883.	635.	0.	635.	3175.	-183.
1998/1999	2778.	635.	3413.	1657.	883.	635.	0.	635.	3175.	-238.
1999/2000	2834.	635.	3469.	1657.	883.	635.	0.	635.	3175.	-294.

REFERENCES

1. NB Power Load Forecast 1985-2000, April 1985.

2. NB Power "Annual Report - Load and Resources Review"